5. GAS DEMAND AND SUPPLY

5.1 PIPELINE CAPACITY ADDITIONS

Prior to the autumn of 2001, no substantial pipeline expansions had been built in New York since the Iroquois addition in 1991. The EIA has noted that, as a result of this limited supply expansion and substantial gas demand growth, downstate gas deliveries in the New York City area have approached their throughput limits.[27] However, substantial expansion of the New York pipeline infrastructure is already under way. With projects that have recently been completed or are expected to be completed by the end of 2003, a total of 465 MDT per day of new delivery capacity will be available into the downstate region, for an increase in delivery capacity of 16 percent. This additional capacity exceeds forecasted growth in nongeneration gas demands through at least 2005.

In addition to the 465 MDT per day of expansions already being added, there are numerous pipeline proposals for new and expanded capacity to serve New York, totaling more than one billion cubic feet per day of capacity. Not all of the projects will be built, as some are competing to effectively serve the same markets and some are seeking markets that will not evolve. A substantial portion of the proposed capacity has begun to clear regulatory hurdles; the FERC has provisionally approved projects that could provide a total of approximately 800 MDT per day, primarily to the downstate region (an increase in capacity of approximately 27 percent).

The set of the proposed pipeline projects are that have recently been added or will be in place before November 1, 2003, are included in all of our pipeline capacity expansion cases. These projects include the following:

- **Iroquois Athens** is an expansion that is designed to serve a 1,080 MW combined cycle power plant under development in Athens, New York. Under the plan, Iroquois will expand its existing capacity by 70 MDT per day by installing a 10,000 horsepower compressor on the existing system, with a start-up date of September 2003. In addition to increasing deliverability to the Athens plant, Iroquois believes that the new compressor will increase reliability on their system as a whole.

- **Iroquois Eastchester** received its FERC Certificate in December 2001, and is expected to go forward with an additional 230 MDT per day in April 2003. Thirty miles of new pipe will be laid from Northport, New York, under Long Island Sound into New York City. The new segment of pipeline will be accompanied by upstream additions and modifications to compression at Dover, Boonville, Wright, Athens and Croghan, New York.

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[27] Status of Natural Gas Pipeline System Capacity Entering the 2000–2001 Heating Season, EIA *Natural Gas Monthly*, October 2000; *Natural Gas Transportation—Infrastructure Issues and Operational Trends*, EIA Natural Gas Division, October 2001.

- **Transco MarketLink** was originally planned as a three-phase project to bring 700 MDT per day into the New York/New Jersey area from the Midwest. Over the past two years, the project has undergone significant revision, and is currently approved as a two-phase project. Phase I was completed in December 2001, and has a capacity of 166 MDT per day into the region. **Transco Leidy East** has been incorporated into Market Link Phase II and is expected to be in-service by November 2002. Of the 130 MDT per day of capacity from Phase II, 25 MDT per day are expected for New York State.

- **Other Projects** represent other expansions in the New York area, although they are not necessarily directed to New York. From all of this capacity, we have included 25 MDT per day of deliveries into downstate New York, to be in service by November 2003.

    Algonquin Hanover Compression is expected to bring 135 MDT per day of capacity into the NJ/NY area on Texas Eastern.

    Stagecoach Storage is a high-deliverability underground storage project in New York and Pennsylvania connecting to the Tennessee Gas Pipeline. It is planned to have up to 500 MDT per day of deliverability.

In total, we have included 465 MDT per day of capacity that was either recently installed or will be installed prior to November 2003. For the period after 2003 we have not selected any one proposed pipeline expansion or new pipeline project over another. Rather, we have accounted for the proposed projects through "generic" capacity expansions. By using generic pipeline expansions, we are able to reflect our fundamental assessment that new pipeline capacity will follow the commitments of power generators to contract for pipeline capacity to support their projects. As previously stated, it is unrealistic to hypothesize substantial new power generation capacity without assessing the incremental pipeline capacity that is being marketed to support that incremental load. Our generic expansion cases into the downstate area span the potential range of additional capacity that could be created by the proposed projects.

The pipeline expansion cases represent the following:

- No additional expansion after November 2003 (beyond the 465 MDT per day discussed above).

- Additional Pipeline capacity expansions (beyond the 465 MDT) into the downstate market of 300, 400, 500 and 800 MDT per day.

5.2 Gas Demands for Traditional End Users

The demand for gas by traditional end use gas consumers (*i.e.*, all gas demands except those for electricity generation) in New York is projected to grow a total of just over 6 percent between

2002 and 2005, with all of that growth effectively in the downstate region, as shown in Table 6.[28] This growth represents the New York LDCs' outlook that each LDC provides annually to the New York Public Service Commission.

Table 6
New York State Gas Market
2002 and 2005
Million DekaTherms

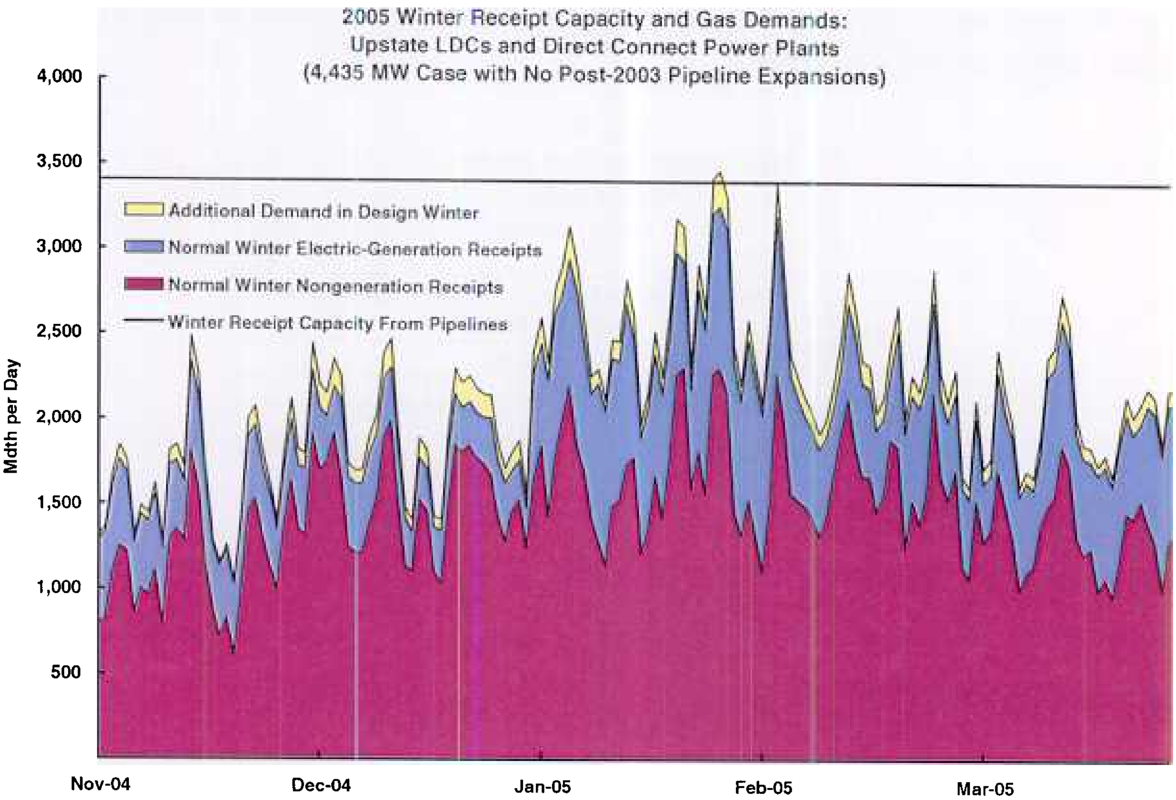
	Gas Market, Excluding Electric Generation (Normal Weather)		
Year	Downstate	Upstate	Total
2002	451	363	814
2005	500	367	867
Growth	**10.9%**	**1.1%**	**6.5%**
2002 Share	**55%**	**45%**	**100%**

The upstate and downstate markets are quite different. Historically, the upstate market has represented about 45 percent of the State's LDC demand, while the downstate market is about 55 percent of the State's demand. Projected growth in the nonpower sector over the next five years is significant in the downstate area.

In general, the infrastructure in the upstate area is relatively robust and there is a substantial cushion between peak gas demands and physical gas system deliverability during a year with normal winter weather. Our analysis shows that upstate capacity will remain adequate through at least 2005. This finding is illustrated in Figure 17, which depicts the upstate gas supply/demand balance, under both normal and extreme (design winter) weather conditions, for our case with the most electric generation additions (4,435 statewide) and no new pipeline capacity. This case represents a "worst case" scenario, since peak-day gas demands among generators are at their highest and deliverability is at its lowest. Given the low growth rate in traditional gas demand for this region and the amount of gas-fired capacity additions proposed for the area, the cushion between peak gas demands and winter deliverability in a normal winter will remain more than adequate over the forecast period. During a cold (design weather) winter, gas demands would approach physical capacity limits on a few days, and exceed capacity on one day. However, for this brief period when a small amount of the maximum potential gas demand cannot be fully supplied, the upstate area has more than sufficient substitute, oil and other non-gas-fired generating capacity to allow electric demands to be met.

[28] Traditional end users include residential, commercial, industrial, and transportation customers. Forecasted demand growth includes potential new uses among these consumers, such as expanded use of natural gas for transportation.

Figure 17



This is not meant to imply that there are no areas in the region where gas deliverability may be limited. We recognize that within individual upstate LDCs, there may be deliverability constraints in portions of the system. However, our analysis treats each LDC as a single node and we did not analyze deliverability conditions within the LDC.

Downstate conditions are substantially different than those found upstate. Peak gas demands in the downstate area have required interruptions in deliveries to interruptible customers in the winter. During the course of a typical winter, residual fuel oil is routinely substituted for gas in some large commercial and industrial boilers as well as steam electric power plants. When gas is higher priced than residual fuel oil, the decision is driven by economics—customers that can use either fuel choose the lower cost fuel. As discussed in section 1.1 earlier, historically this has been the case for dual-fueled electric generation in New York. When gas prices rise, reflecting its limited availability, the gas and electric markets clear by using substitute fuels (oil) for electric generation—leaving gas supplies for those consumers with limited/no options for substitution.

Downstate there is reasonably strong growth in the demand for gas outside of that used for electric generation—a total of almost 11 percent between 2002 and 2005. Our analysis shows a need for the pipeline capacity that is currently being added into the downstate area to serve this potential growth, even if the gas requirements for electric generation do not increase over historical levels. We expect that the downstate non-power-generation gas market growth itself increases the average daily demands that the LDCs must serve. If the LDCs maintain their full design winter reserve, then the daily capacity into this market would have to increase by 292 MDT per day.

In the future, gas deliverability in this area will be stressed by the forecasted growth in both traditional gas markets and the increased demand that would be created by new power plants. With the pipeline capacity that exists today, in both a normal and a design winter, the LDCs would need to limit deliveries to a portion of their interruptible gas load in 2002. As the interruptible loads are designed and priced in anticipation of interruptions, there is nothing unusual about such an event. It does point out, however, that the gas delivery capacity in the downstate area is tight during peak winter months.

For 2002 we only included 255 MDT per day out of the total of 465 MDT per day. This amount represents the approximate portion that was expected to be in service during the year at the time our analysis commenced. If the design winter increment on the downstate growth is excluded, then the additional capacity is just sufficient to meet the new load. Without further expansion (beyond the 465 MDT per day included in all cases), the current tightness in this market would remain not much different than it is today. Even with the additional capacity, under normal weather conditions, our analysis shows some minor interruptions of interruptible customers in the winter period, which is not an abnormal event. Given the very mild winter in the first quarter of 2002, the normal weather assumption that underlies our forecast is unlikely to occur. As a result, this capacity limitation may not emerge until next winter (albeit quite small, and manifested only with the interruptible customers).

5.3 GAS DEMANDS FOR ELECTRICITY GENERATION

The maximum potential demand for gas by electric generators increases by 2 percent between 2002 and 2005. The relatively modest growth in maximum potential gas demands reflects a large shift downstate away from relatively inefficient steam gas units to the new, more efficient CCs, as shown in Table 7. As shown, the maximum potential downstate demand for gas by electric generators in 2002 is 305 MDT. This total represents the total demand for fuel (*i.e.*, Btus, irrespective of their source—gas or oil) by gas-capable generating units.

As shown in Table 7 most of the 2002 demand is from generators that take deliveries at relatively low pressures (*e.g.*, dual-fired gas/oil units). As many of these units burn oil routinely (sometimes due to better economics for oil, other times due to seasonal interruptions of gas), actual historical downstate gas use is well below any estimate of maximum potential fuel demands by these units. For example, as shown in Figure 1 in the first chapter of this report, gas accounted for approximately 50 percent of the total fuel burn of dual-fueled units in New York State during 2000 and 2001.

Table 7
Maximum Potential Gas Demands
Among Electric Generators
New York State
2002 and 2005
Million DekaTherms

	Gas/Oil Dual-Fueled Steam Plants	Combined Cycle Gas Turbine Gas-Only Steam Plants	All Plants with Gas Capability
Year	Downstate		
2002	273	32	305
2005	95	195	290
Growth			-5.1%
2002 Share	56%	7%	63%
2005 Share	19%	39%	58%
Year	Upstate		
2002	176	7	183
2005	68	140	208
Growth			13.8%
2002 Share	36%	2%	38%
2005 Share	14%	28%	42%
Year	Total		
2002	448	40	488
2005	163	335	498
Growth			2.0%
2002 Share	92%	8%	100%
2005 Share	33%	67%	100%

Absent any load growth, the 4,435 MW of new gas-fired, CC units (taking deliveries at high pressure) in our highest electric case, would simply substitute for existing steam electric plants and potential gas demand would go down. The substantial number of new combined cycles included in the 4,435 MW case effectively reduces the total potential gas demand between 2002 and 2005 even though the total downstate generation from gas increases.

It is important to note that satisfying the entire gas market year-round by pipeline is a very unlikely scenario as it would be economically unwise. A distinctly seasonal gas market will not produce high load factors for pipeline expansion projects if the expansions are sized to meet maximum potential winter peak demands, including demands by electric generators. Gas pipelines in the Northeast are typically sized to operate at very high load factors for the winter season. The extreme peaks are served at a lower cost by high-deliverability LNG and curtailing interruptible customers (if they have not already switched to their alternate fuel based on economics). The longer shoulder periods are served by winter storage services. If all winter peaks were served by year-round pipeline capacity, released capacity would be available at low prices for most of the year, making it extremely unattractive for those customers that purchased long term firm capacity.

5.4 ANALYTICAL RESULTS: GAS AND OIL USE FOR ELECTRICITY GENERATION

Our analysis shows that with the addition of 465 MDT per day of pipeline capacity assumed to be in place by November 2003, New York will have sufficient gas delivery capacity to supply the amounts of gas required for generation under all 2005 generation and pipeline addition scenarios, provided the existing ability to burn oil is maintained. For each new generation capacity scenario, there is a range of feasible combinations of gas pipeline additions and oil-burning capability that allows the fuel needs of electric generators to be met. This range of combinations illustrates the trade-off between gas pipeline capacity and local Btu storage. There are advantages and disadvantages associated with each.

- Pipeline capacity additions of between 300 MDT per day and 800 MDT per day (beyond the 465 MDT per day) would provide additional benefits to the electricity and natural gas systems, including enabling the use of larger quantities of cleaner-burning natural gas and the potential for better contingency protection.
- The more natural gas pipeline capacity built and used to serve electricity generation, the more dependent the electric system is on natural gas availability and the more exposed it is to natural gas price volatility.

The remainder of this section presents the analytical results underlying these basic conclusions from our electric and gas system modeling, beginning with annual generation among gas-fired power plants.

Tables 8, 9, and 10 illustrate the annual amount of electric generation produced by gas-fired and dual-fueled units, by fuel type. Each table shows annual generation for the downstate region under each pipeline additions scenario for one of our new generating capacity cases. Table 8 begins with the results from the 4,435 MW generation expansion case. The first column of the table shows how much each type of gas-capable unit would generate if its maximum potential gas demand were fully supplied. Note that in this unrestricted gas delivery case, 75 percent of the gas-fired generation comes from CCs. Because gas deliveries are not restricted, the maximum potential demand is supplied on every single day.

The second column of the table shows the gas-capable units' generation in the scenario with no additional pipeline capacity added into the downstate region post 2003. In this case, 25 percent of the generation from new CCs using gas would need to be replaced by generation from non-gas-fired units or increased imports into the downstate region (from either the upstate region or outside New York). Note that the total generation among the units represented in this table decreases when pipeline constraints are encountered. This is due to increased imports into the downstate region.

The remaining columns show the results from the pipeline expansion scenarios with 300, 400, 500, and 800 MDT per day of new capacity. As more pipeline capacity is added downstate, the CCs and gas-fired steam units receive an increasing portion of their maximum potential demands. In the 300 MDT per day case, 95 percent of the gas needed to allow CCs to operate on gas all of the times they wish to run can be supplied. In this case, there are 280 days with no restrictions in gas deliveries, and on most days when capacity is constrained, a large portion of the potential demand can be supplied. Incremental pipeline capacity of 400 MDT per day increases the number of operational days with no restrictions at all to 318 while allowing 98 percent of the gas power market demand to be served. For the case with 800 MDT per day, 100 percent of the maximum potential demand for gas is met.

Table 8
Generation by Gas-Fired and Dual-Fueled Units (GWh)
Downstate Region 2005
4,435 MW Generating Capacity Additions Case

	Maximum Potential Gas Demand	No Post 2003 Pipeline Expansions	300 MDT/day Expansion Into Downstate	400 MDT/day Expansion Into Downstate	500 MDT/day Expansion Into Downstate	800 MDT/day Expansion Into Downstate
Combined-Cycle Units Fueled by Gas	27,856	20,762	26,520	27,304	27,734	27,856
Other Units Fueled by Gas	9,003	8,217	8,656	8,748	8,786	9,003
Units Fueled By Oil	0	1,705	1,038	567	296	0
Total	36,858	30,684	36,214	36,618	36,816	36,858
# of Days When Maximum Potential Gas Demand is Supplied	365	140	280	318	342	363
% Served of Maximum Potential Gas Demand	100%	79%	95%	98%	99%	100%

Table 9 shows the analogous results from the case with 1,780 MW of new generating capacity. Looking at the generation mix in the unrestricted case shows that generation by CCs is more than 60 percent lower than in the 4,435 MW Case, as far less new gas-fired capacity is added. In the case where no pipeline capacity is added after November 2003, the generators' maximum potential gas demands can be met on 228 days of the year, and 91 percent of the potential demand is supplied. If an additional 300 MDT per day of pipeline capacity is added, 98 percent of the potential gas needs for generation can be met, with unlimited deliveries on 318 days.

Table 9
Generation by Gas-Fired and Dual-Fueled Units (GWh)
Downstate Region 2005
1,780 MW Generating Capacity Additions Case

	Maximum Potential Gas Demand	No Post 2003 Pipeline Expansions	300 MDT/day Expansion Into Downstate	400 MDT/day Expansion Into Downstate	500 MDT/day Expansion Into Downstate	800 MDT/day Expansion Into Downstate
Combined-Cycle Units Fueled by Gas	9,881	9,340	9,880	9,880	9,881	
Other Units Fueled by Gas	20,310	18,240	19,626	19,832	20,310	
Units Fueled By Oil	0	1,883	591	413	0	
Total	30,191	29,462	30,098	30,126	30,191	
# of Days When Maximum Potential Gas Demand is Supplied	365	140	280	318	365	
% Served of Maximum Potential Gas Demand	100%	91%	98%	98%	100%	

Table 10 shows downstate generation and deliveries for the 1,030 MW case. With the pipeline capacity remaining fixed after November 2003, 93 percent of generators' potential gas demands can be met, with deliveries unrestricted on for 248 days of the year. If an additional 300 MDT per day of pipeline capacity were added, unrestricted demands could be fully served 323 days of the year and 98 percent of the gas requirements would be fully met.

Table 10
Generation by Gas-Fired and Dual-Fueled Units (GWh)
Downstate Region 2005
1,030 MW Generating Capacity Additions Case

	Maximum Potential Gas Demand	No Post 2003 Pipeline Expansions	300 MDT/day Expansion Into Downstate	400 MDT/day Expansion Into Downstate	500 MDT/day Expansion Into Downstate	800 MDT/day Expansion Into Downstate
Combined-Cycle Units Fueled by Gas	4,682	4,641	4,679	4,682		
Other Units Fueled by Gas	24,045	21,993	23,458	24,045		
Units Fueled By Oil	0	2,093	589	0		
Total	28,727	28,727	28,727	28,727		
# of Days When Maximum Potential Gas Demand is Supplied	365	140	280	365		
% Served of Maximum Potential Gas Demand	100%	93%	98%	100%		

Table 11 presents a summary of the results from our electric and gas model analysis. For each generating capacity and pipeline expansion scenario, estimates of gas and oil use are shown. The maximum potential gas demands are shown first (in the fourth column of the table). The maximum potential gas demands are calculated by assuming that there are no deliverability constraints limiting the amount of gas used for electric generation. Columns six through ten list the projected amounts of gas, and the corresponding amounts of oil, that could be used for electric generation under each of the pipeline expansion cases. The amounts of gas consumed are calculated by assuming that generators will always burn gas if the pipeline system is able to deliver it. Correspondingly, the amounts of oil used for electric generation are calculated by assuming generators will only burn oil during those periods when the gas delivery capacity has been fully utilized. Note that estimated gas and oil use do not always sum to the maximum potential gas demand. The difference is attributable to changes in net imports and exports and changes in generation among units that burn other fuels.

Table 11
Summary of Gas and Electric Modeling Results
From All Gas and Electric Expansion Scenarios

All of New York

				Estimated Gas and Oil Consumption (MMDT)				
Year	Net Electric Generating Capacity Additions (Post 2002)	Fuel	Maximum Potential Gas Demand (MMDT)	No Post 2003 Pipeline Expansions	300 MDT/day Expansion into Downstate Region	400 MDT/day Expansion into Downstate Region	500 MDT/day Expansion into Downstate Region	800 MDT/day Expansion into Downstate Region
2002	N/A	Gas	488	453	N/A	N/A	N/A	N/A
		Oil	-	18	N/A	N/A	N/A	N/A
2005	1030 MW	Gas	503	478	495	503	503	503
		Oil	-	24	8	-	-	-
	1780 MW	Gas	496	468	487	489	496	496
		Oil	-	22	8	6	-	-
	4435 MW	Gas	498	439	484	491	494	498
		Oil	-	18	11	6	4	-
2010	5015 MW	Gas	588	517	570	576	580	588
		Oil	-	95	22	12	6	-

Downstate New York

				Estimated Gas and Oil Consumption (MMDT)				
Year	Net Electric Generating Capacity Additions (Post 2002)	Fuel	Maximum Potential Gas Demand (1,000 MMDT)	No Post 2003 Pipeline Expansions	300 MDT/day Expansion into Downstate Region	400 MDT/day Expansion into Downstate Region	500 MDT/day Expansion into Downstate Region	800 MDT/day Expansion into Downstate Region
2002	N/A	Gas	305	273	N/A	N/A	N/A	N/A
		Oil	-	16	N/A	N/A	N/A	N/A
2005	296 MW	Gas	285	263	279	285	285	285
		Oil	-	22	6	-	-	-
	1,046 MW	Gas	282	257	275	282	282	282
		Oil	-	20	6	-	-	-
	2,513 MW	Gas	290	232	277	283	286	290
		Oil	-	18	11	6	3	-
2010	3,093 MW	Gas	336	268	320	327	331	336
		Oil	-	94	21	11	5	-

The results presented in the table highlight several key findings.

- The statewide maximum potential gas demand for electric generation is higher in all 2005 cases than in the corresponding cases for 2002. This result is due to growth in electric loads as well as the presence of more base-load, gas-fired generation.

- Comparing the projected fuel use across capacity-addition scenarios shows that for a given level of pipeline capacity, gas deliveries typically decrease when a larger amount of new electric generation capacity is added. As more combined-cycle generating units (CCs) are added in the downstate area, the limited amount of gas available in those areas is able to support more generation due to the relative efficiency of the new units. Hence, less electric generation is needed from other areas, and less total gas is consumed.

- The efficiency advantage of new CCs also lowers the need for generation from steam units fueled by residual oil. As a result, oil use generally also declines as more new generators are added.

- Pipeline expansions totaling 800 MDT per day into the downstate area are sufficient to meet the maximum potential demands of generators in the case with the most new electric capacity (4,435 MW). Fewer pipeline expansions are needed to meet the maximum potential demands if less new generation capacity is added. In the case with 1,780 MW added, only 500 MDT per day is required; in the case 1,030 MW, 400 MDT per day is sufficient to meet the maximum potential gas requirements.

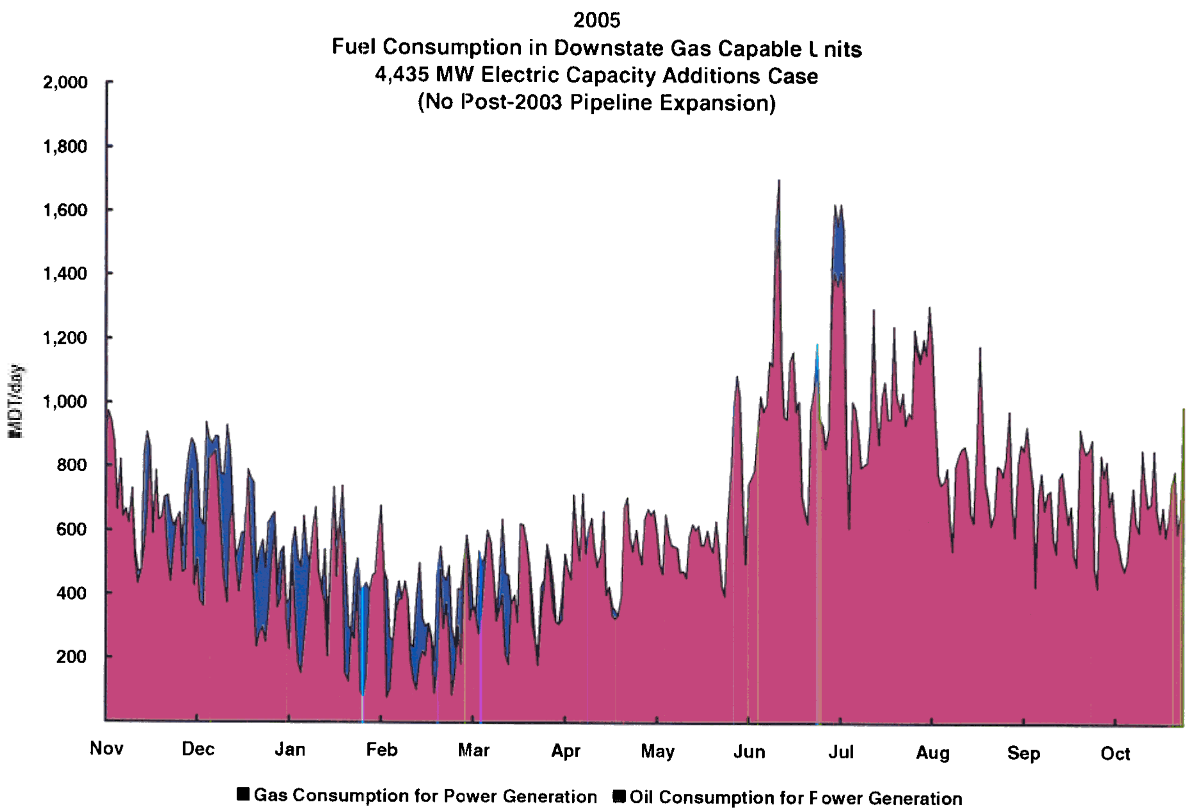
- Our case for 2010 shows that annual fuel demands among gas-fired and dual-fueled generators will increase approximately 20 percent between 2005 and 2010. This substantial increase in generation reflects the fact that existing base load units (nuclear, coal, and hydro) are already operating near full capacity in 2005. Hence, incremental electric load growth will need to be met either by new CCs or by existing steam units that have traditionally operated at low annual utilization levels. The 2010 maximum potential gas demand of generators can be met with 800 MDT per day of pipeline expansions into the downstate region.

As the issue of pipeline adequacy for the growth in the generation market is one of the principal areas of interest for this study, we have shown the daily deliveries of gas and oil to the Downstate electric generators for the 4,435 MW electric case under each of the pipeline expansion scenarios that we analyzed. The data are for the full year. Figures 18-22 illustrate the gas deliveries and the oil consumed (primarily residual fuel oil in dekatherm equivalents).

Figure 18 depicts gas (shown in maroon) and oil (shown in blue) usage for 2005 in the case where there are no post-2003 expansions in gas pipeline or LDC capacity. As illustrated, a substantial quantity of oil is consumed in this scenario during the winter, as well as on a few peak days in the summer.[29] Figure 19 depicts gas and oil usage with 300 MDT per day of additional pipeline/LDC capacity into the downstate region. Two things change as a result. The amount of oil used declines substantially. Oil is used in dual-fuel or oil-only units only in the winter. Additionally, as the high efficiency CCs are substituted for the older steam electric units, the total fuel use in the downstate area declines.

As shown in Figure 20, adding an additional 100 MDT per day (for a total of 400 MDT per day) has very little impact on the relative amounts of gas and oil burned to generate electricity in the downstate area, since there was very little oil burned in the 300 MDT per day case as a starting point. Oil is still used in dual-fuel units for a few days, even in the 500 MDT per day case shown in Figure 21. Figure 22 shows that, with the entire 800 MDT/d of incremental gas pipeline/LDC capacity expansions, oil use for electric generation is completely eliminated, even during the winter.

Figure 18



[29] Projected oil usage is compared with historical levels in section 5.5 below.

Figure 19

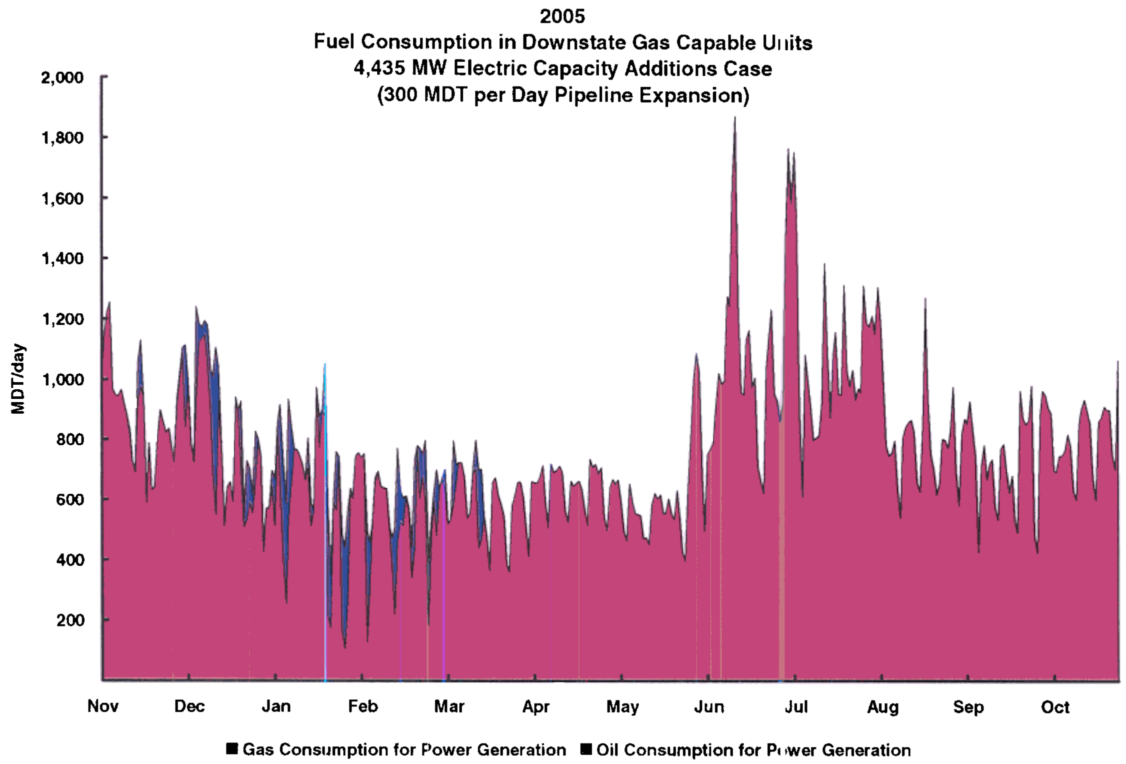


Figure 20

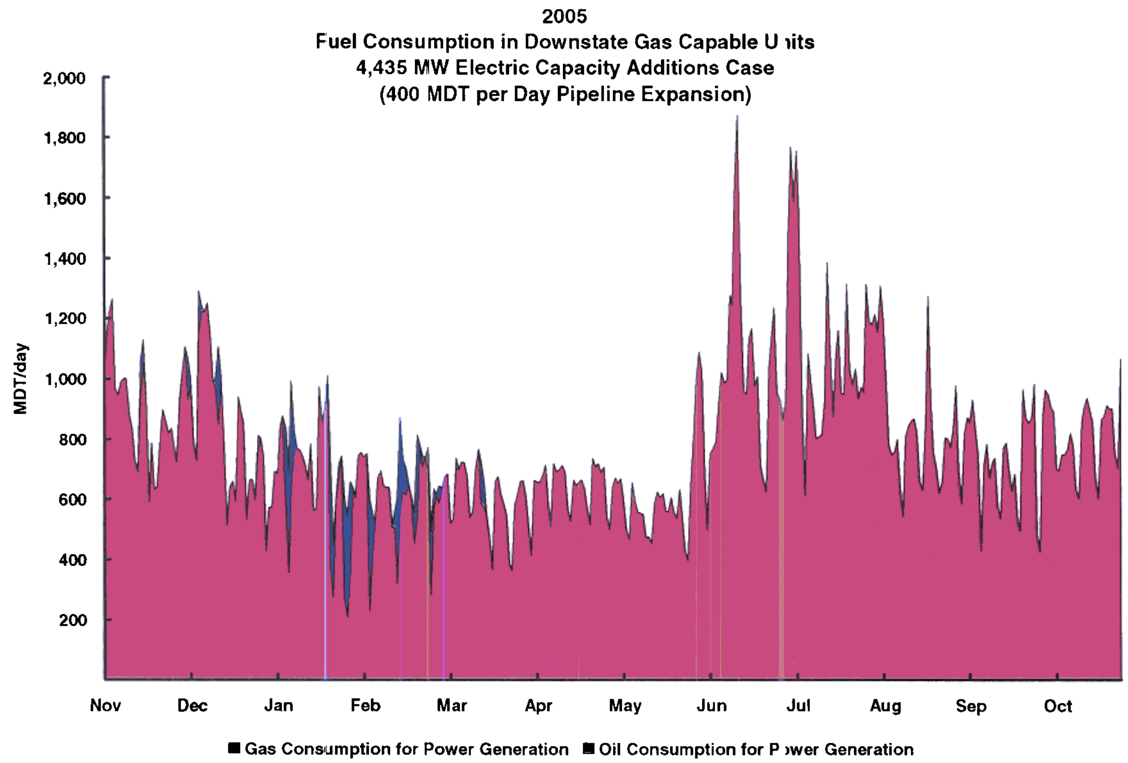


Figure 21

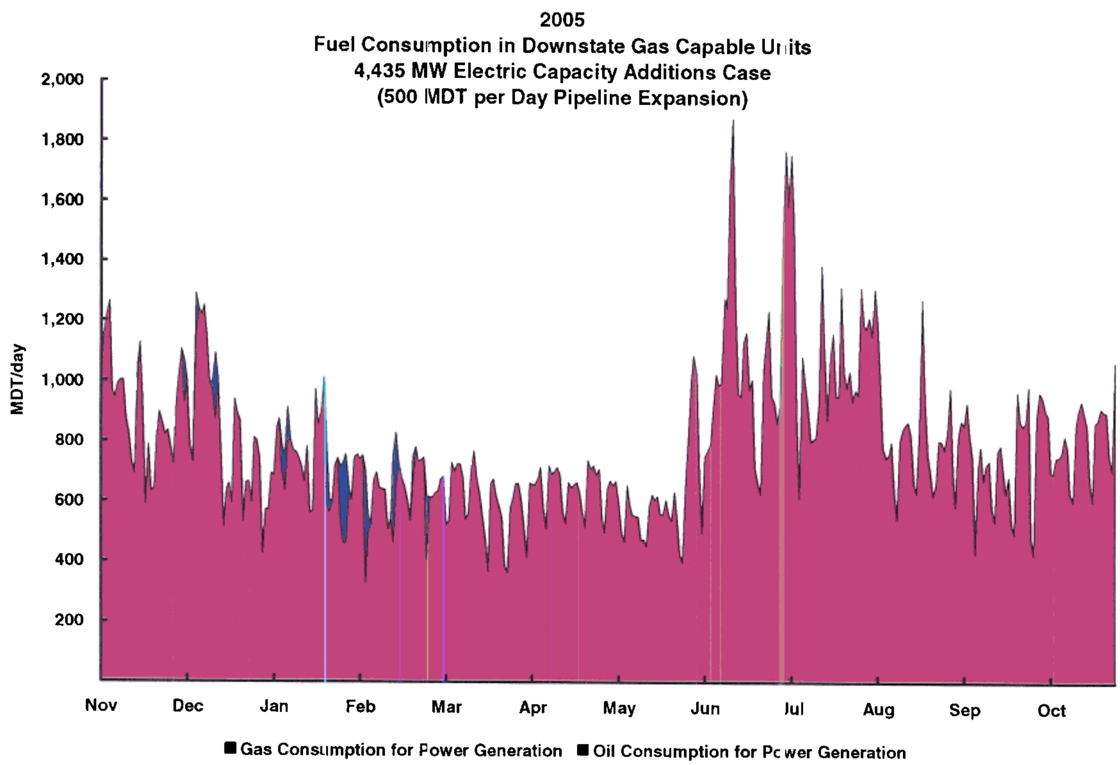
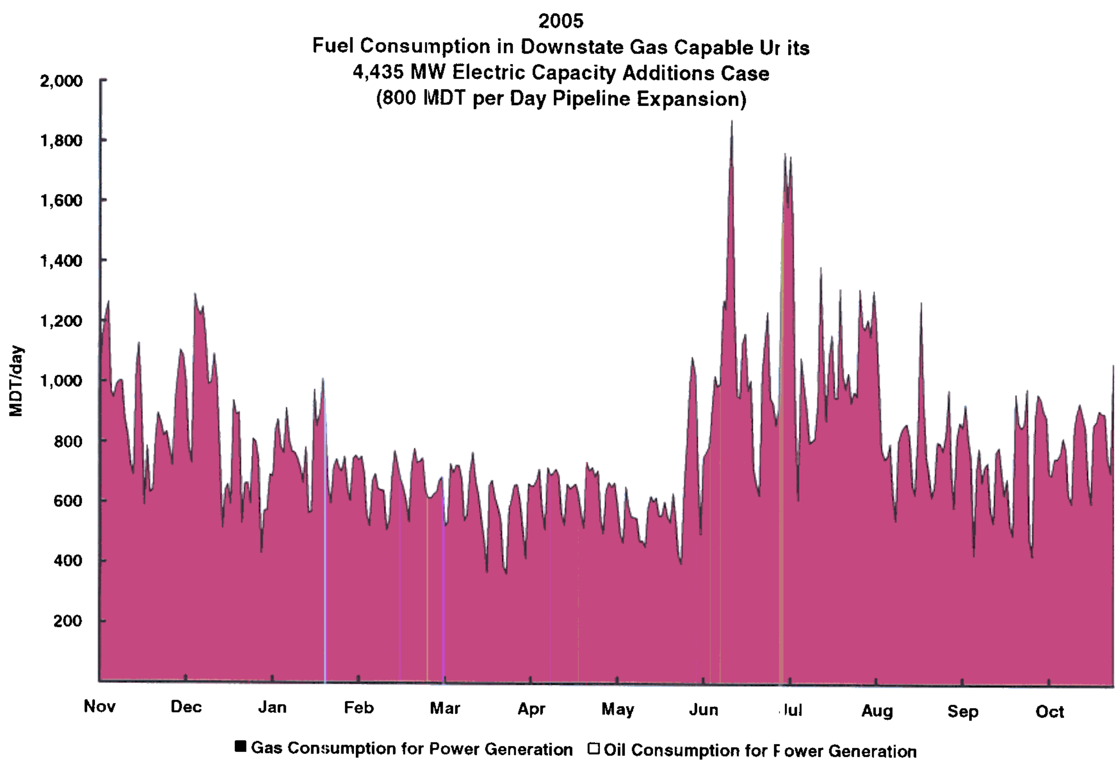


Figure 22



Figures 23, 24, and 25 show available and utilized capacity into an example gas load pocket in the downstate area under the case with 4,435 MW of capacity and various levels of pipeline expansion. For different levels of pipeline expansion, the charts illustrate chronologically over the year the utilization of gas delivery capacity and the periods when oil needs to be burned. The green shaded area represents the capacity available for deliveries to electric generators (after nonpower demands have been met). The maroon portion represents estimated deliveries to electric generators. During periods when delivery capacity is fully utilized, the green area is not visible behind the maroon. The yellow area illustrates the amount of oil that is burned by electric generators when gas pipeline capacity is fully utilized.

- If no pipeline expansions are added in the 2003–2005 period, the delivery capacity into the area is fully utilized on many days. As a result, some oil is burned during many days in the winter and a few days in the summer.

- If downstate pipeline capacity is increased by 300 MDT per day, the full capacity is required on substantially fewer days and less oil is burned.

Figure 23

2005
Fuel Burn for Electric Generation in a
Gas Load Pocket in the Downstate Region
(No Post-2003 Pipeline Capacity Expansion, 4,435 MW of New Generating Capacity)

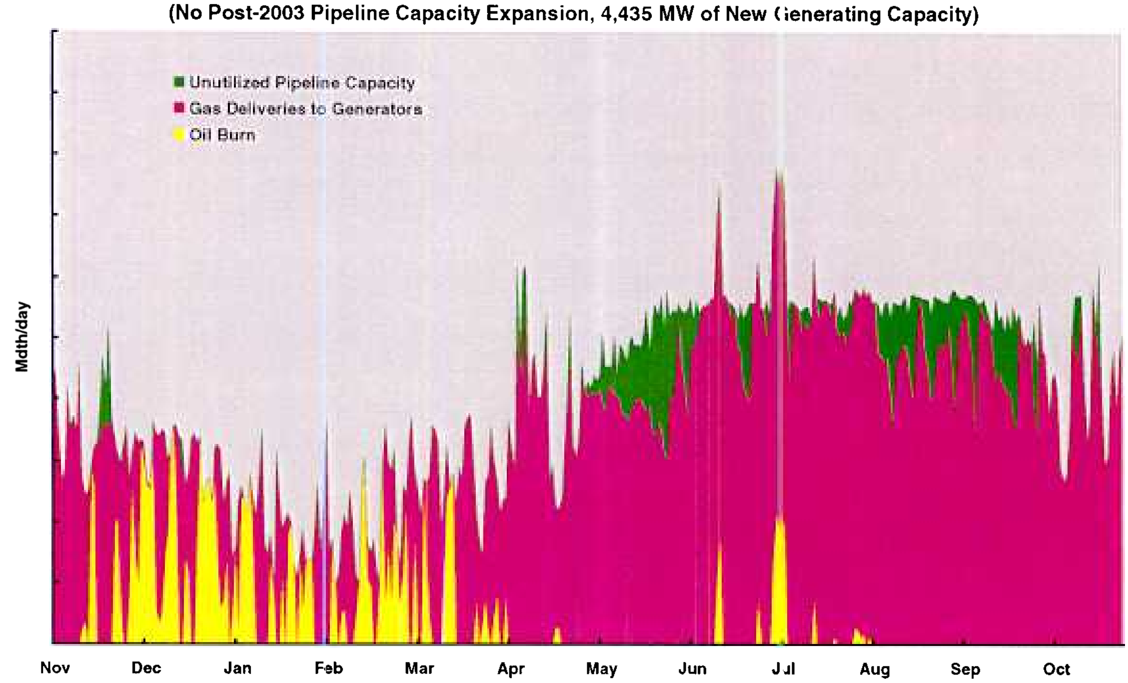


Figure 24

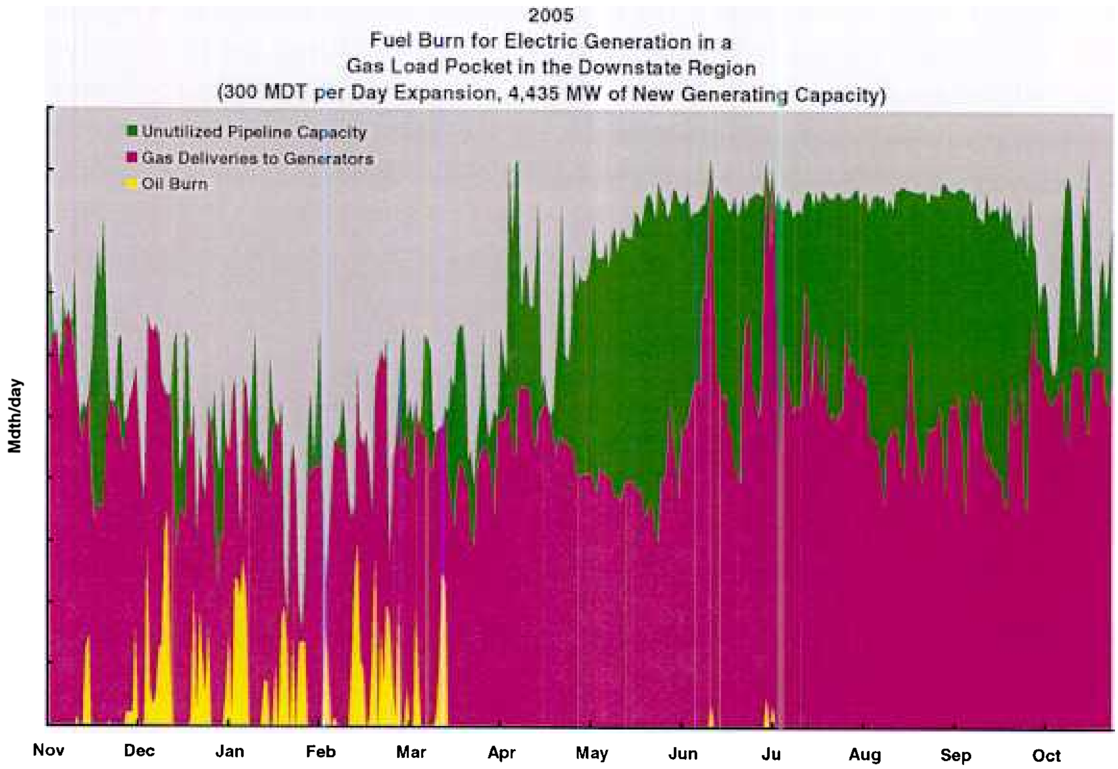
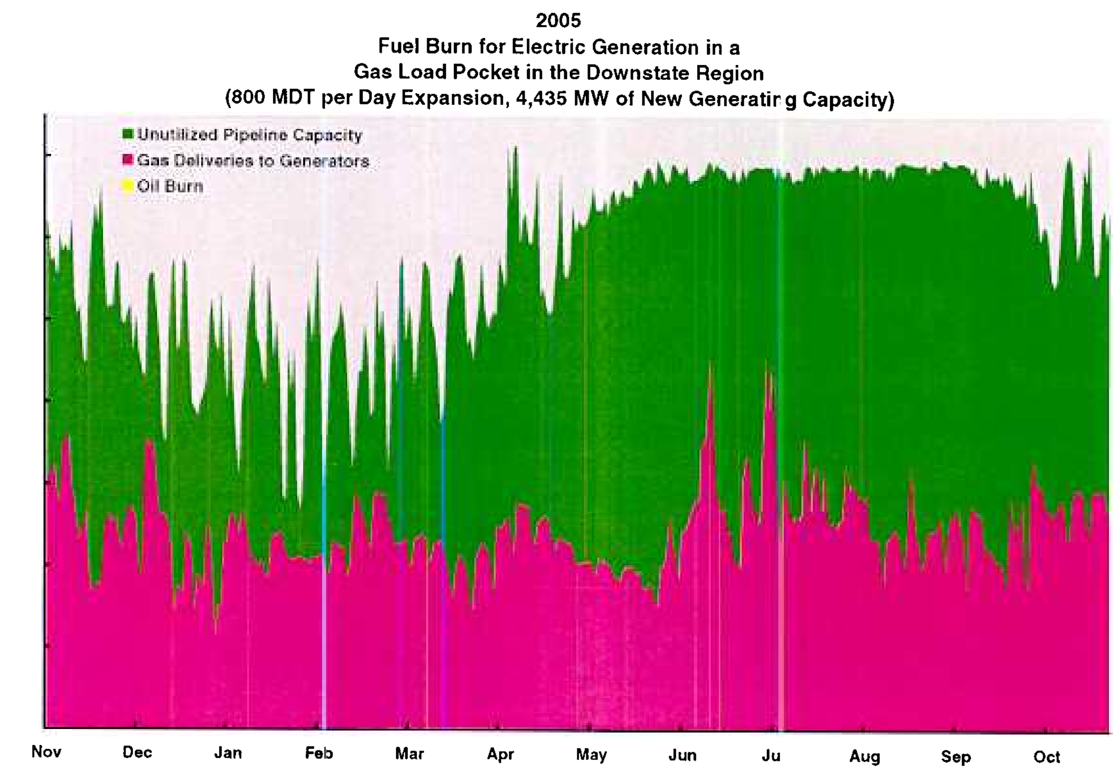


Figure 25



- When all proposed pipeline expansions are included (for an additional 800 MDT per day of capacity), generators' full, maximum potential gas demands can be met and there is substantial unutilized pipeline capacity throughout the year.

Figures 26 and 27 illustrate the seasonality in electric generators' potential gas demands and the amount of capacity available to meet those demands. The graphs depict load duration curves for winter and summer gas deliveries to electric generators in the downstate region in 2005. The bottom area of each graph, shaded blue, shows the projected gas deliveries to the electric generation market in 2005 for our case with 4,435 MW of new electric generating capacity and the most restrictive pipeline expansion scenario (only the 465 MDT per day currently being added). The jagged, yellow area on top of the load duration curve shows the portion of electric generators' maximum potential gas demands that would not be served, given the assumed pipeline capacity.

Figure 26 illustrates the situation for winter 2005 (covering November 2004 through March 2005). Some gas is available for electric generation in the downstate region everyday (after nonpower gas demands are fully met), just not enough to serve the entire potential requirements of gas-capable generators. There are only six days when the maximum potential demands of electric generators are fully met, and deliveries total 56 percent of maximum potential demand. When the maximum potential demands are not met, either the generators will burn oil in place of gas, or other non-gas-fired units will be dispatched in their place. Alternatively, pipeline capacity would need to be expanded if the unserved portions of winter demand were to be met.

The situation in the summer is very different, as shown in Figure 27. Electric generators' maximum potential demands for gas are fully met on 134 of 214 days. And, on those days when there are unmet demands, the shortfall is a relatively small portion of total maximum potential gas demands. As a result, deliveries total 93 percent of maximum potential demand. Hence, little expansion would be needed to meet unrestricted summer gas demands for electric generation.

The addition of 300 MDT per day into the downstate market has a significant effect on the proportion of unrestricted winter gas demands that can be served. Figure 28 shows the winter gas demands and deliveries from Figure 26, but with the additional portion of potential demand that can be met with the pipeline expansion in place shaded red. With the additional capacity, most (89 percent) of the winter maximum potential gas demands for electric generation could be served. In the summer, the additional 300 MDT per day of capacity would be utilized very little as the existing available capacity is very large relative to the maximum potential gas demands for electric generation. The result is that summer demand provides little economic support for the pipeline expansion.

These charts illustrate the dilemma facing owners of new CCs as they consider their gas supply options. Since a pipeline/LDC expansion will require electric generation owners to contract for firm capacity to compensate for its construction, the generators are faced with a situation where, effectively, the entire year-round cost of the pipeline expansion would need to be justified by their desire to secure gas supplies in the winter. In order for the generators to be willing to enter into firm capacity contracts, winter prices in the electricity market would need to be high enough to compensate the generators for the cost of securing firm capacity. Given that electricity prices and spark spreads are typically lower in the winter than in the summer and electricity prices may be, in effect, capped by the generation cost of steam units burning residual oil, owners of CC units may not have an incentive to contract for firm, year-round capacity.

Figure 26

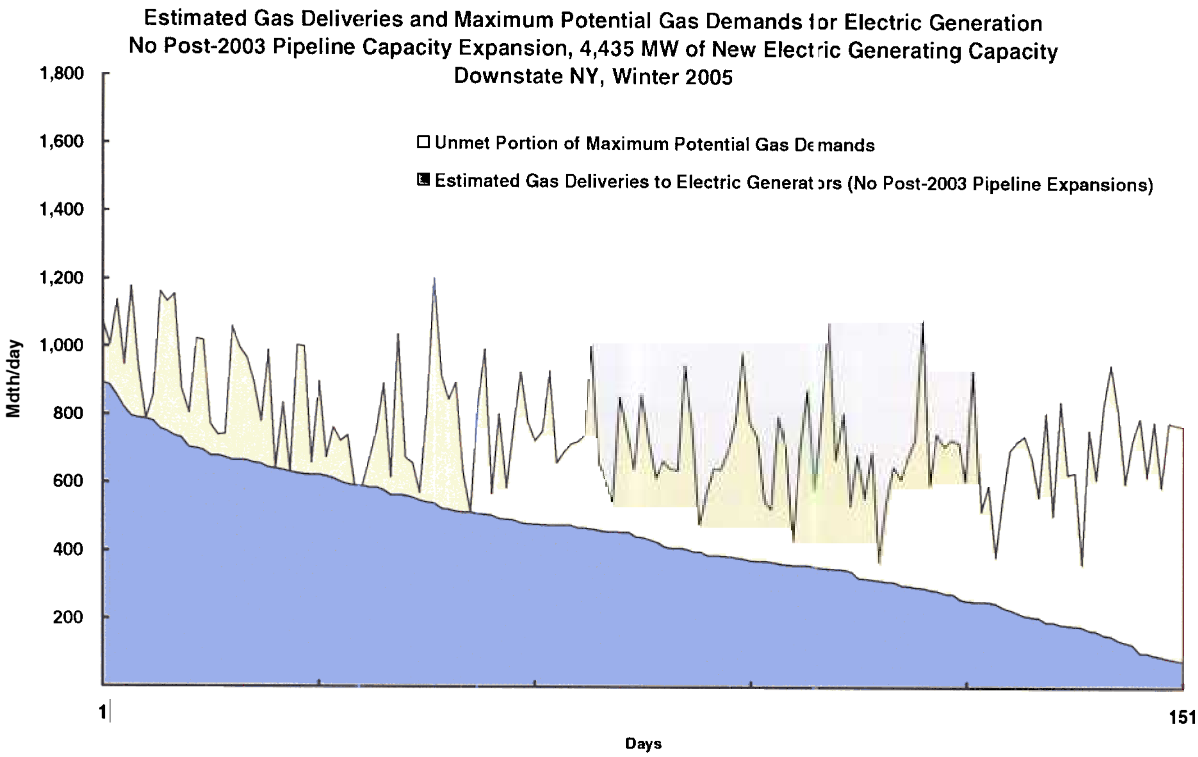


Figure 27

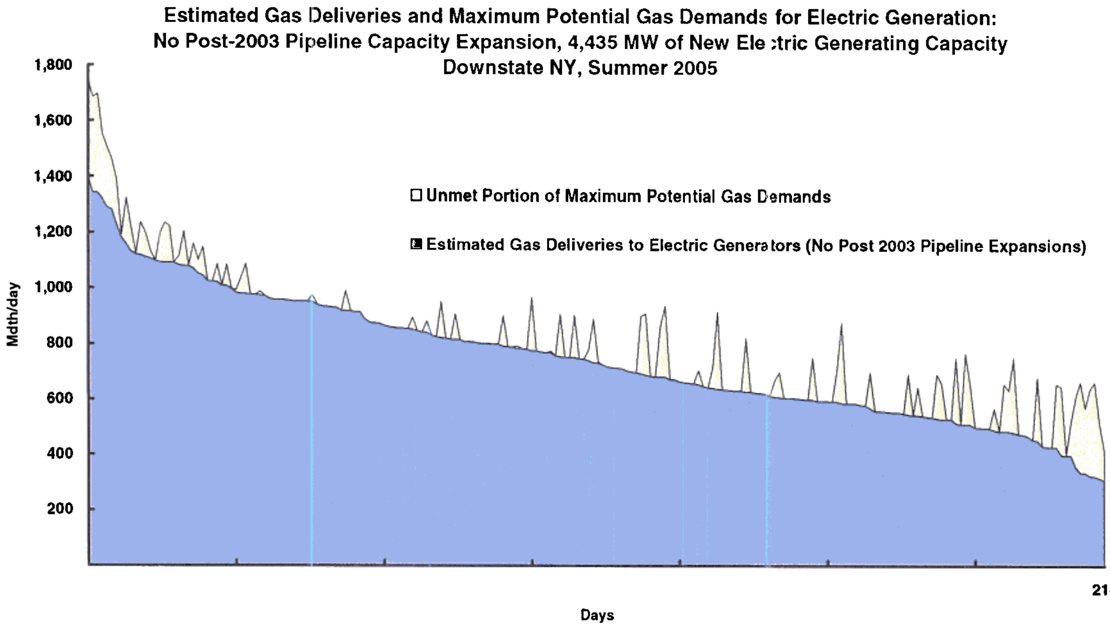
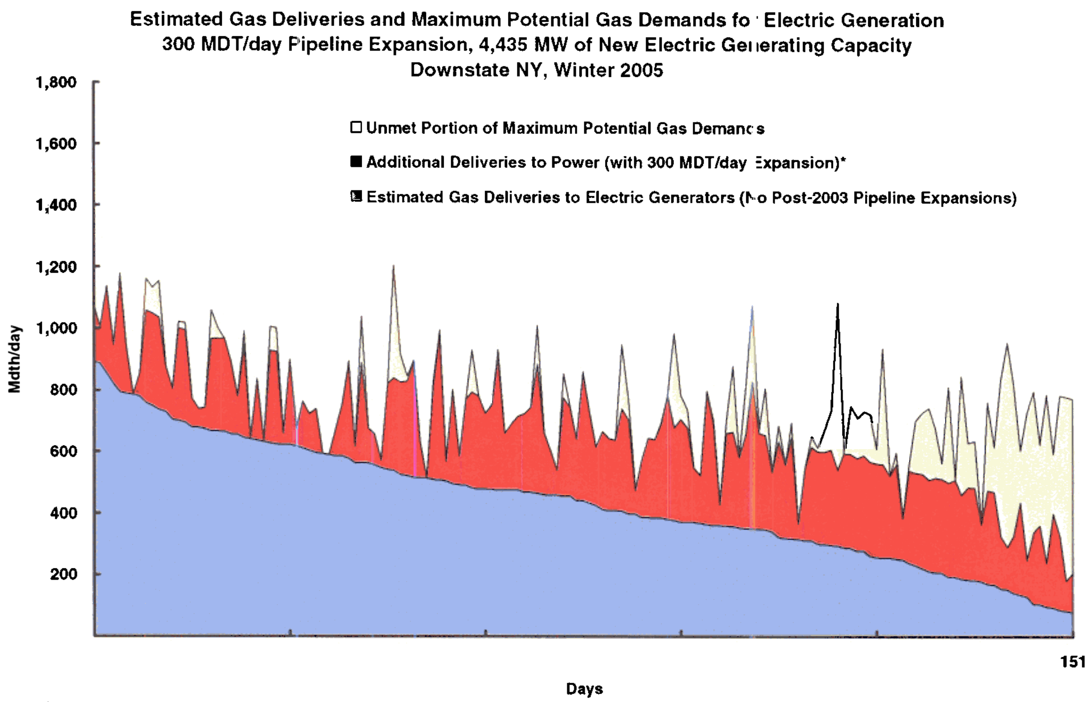


Figure 28



* Represents additional deliveries to the power markets from a 300 MMcf/d pipeline capacity expansion into the downstate region.

The risk to the electric industry is relatively low as long as the substantial overhang of oil-fired generation capacity that currently exists, as shown in Table 12, is not substantially diminished. A substantial decline in the available oil fired generation capacity would increase the probability that the lack of firm pipeline capacity would create a dilemma for the electric industry. As Table 12 illustrates, if no gas were available at all during the winter, the existing oil capable units can substitute completely for those generating units burning gas, allowing electricity demand to be met entirely. Interestingly, it is not actually the oil-fired steam electric capacity that is important here but rather the fuel storage and resupply capability inherent in that capacity.

If the predominately residual oil storage tank capacity were converted to distillate oil tanks, new combined cycle plants were located on sites where the tanks exist, and inventory volumes of distillate oil were maintained, then the issue of winter service gas availability would become moot, even for the CC units (as long as the facilities could burn oil for more than 720 hours and maintain inventory volumes of oil). In the event that the CCs do not install more than a few days of on-site distillate storage, the capacity to refill their tanks becomes important. For the repowering plants, there is often existing barge delivery that would allow refills without introducing substantial stress on the petroleum industry. However, waterways do occasionally freeze, affecting barge deliveries at oil terminals and/or power plant sites. Additionally, during periods of extremely cold weather, the combined demands of electric generators and heating customers have, on rare occasions, made the distillate oil market very tight.

Table 12
Available Substitute Capacity for Gas-Fired Generation, by Type
4,435 MW Electric Capacity Additions Case
Downstate New York
2005

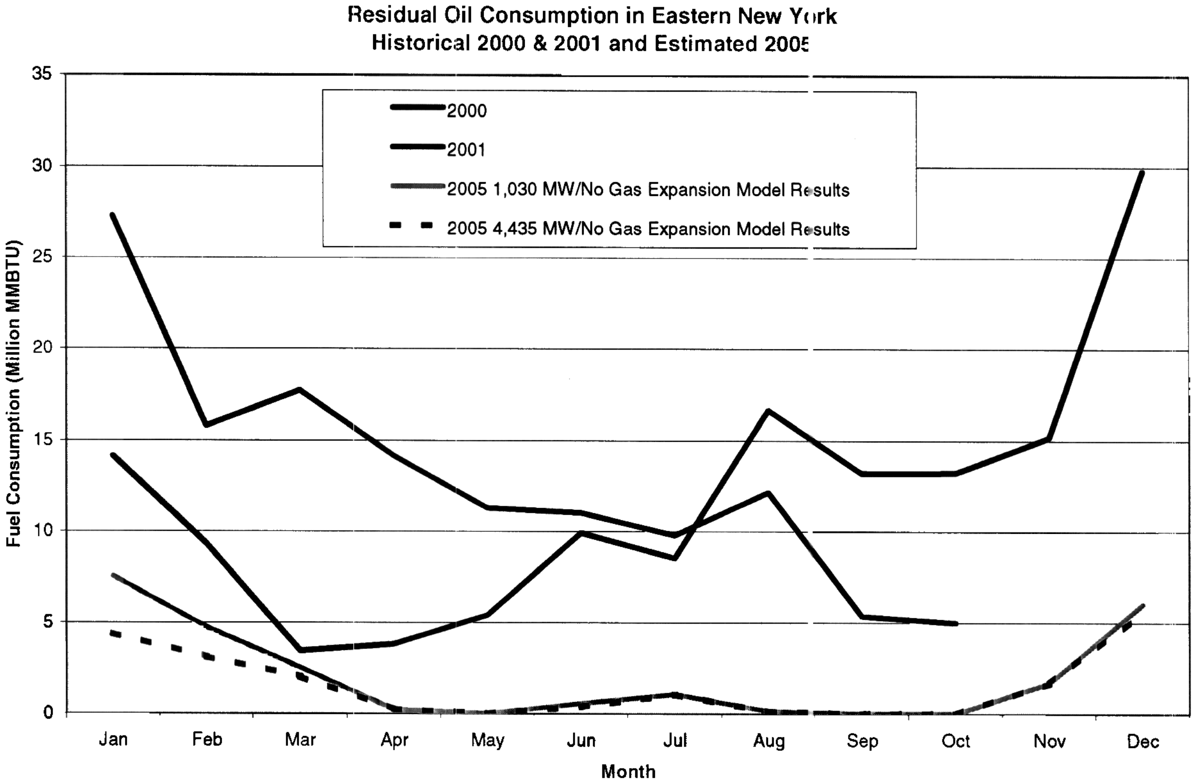
Period	Gas Committed				Available Uncommitted	
	Dual-Fueled Steam Electric Units		Combined Cycle & Combustion Turbine Units		Oil-Fired Peaking and Steam Electric Units	
	Peak Hour Gas-Fired Generation (MW)	Percent (%)	Peak Hour Gas-Fired Generation (MW)	Percent (%)	Peak Hour Oil-Fired Generation (MW)	Percent (%)
Winter Peak	2,037	14%	4,581	33%	7,475	53%
Summer Peak	4,424	34%	5,245	40%	3,376	26%

5.5 Projected and Historical Oil Usage

We have compared our projected 2005 oil burn for electric generation in New York with historical data as a way of validating the reasonableness of our cases. Figure 29 shows 2000 and 2001 historical monthly oil use along with estimated 2005 oil use from two of our model scenarios: our 4,435 MW capacity additions case with no pipeline expansions and the case with 1,030 MW of new CCs and no pipeline expansions. The total amount of oil burned in each of these cases is below the historical levels from both 2000 and 2001. Because the results from the case with 1,030 MW show that more oil is burned than in any other case we have modeled, we can conclude that the amount of oil burned in each of our cases falls below historical levels.

This finding suggests that the levels of oil burn that we have estimated should be feasible under existing and expected future environmental restrictions.

Figure 29



5.6 Extreme Weather Sensitivity Cases

While our analysis indicates that the gas and electric systems can reliably meet their future loads under a range of electric generation and gas pipeline expansion scenarios, oil use by electric generators remains a key substitute for gas during times of peak gas demands (*e.g.*, cold winter days). This is particularly true during extreme winter weather conditions. For example, in 2005 under normal winter weather conditions, if 4,435 MW of generation capacity is added along with 300 MDT per day of post-2003 pipeline expansion, gas pipeline capacity into the downstate market is adequate to satisfy 89 percent of the total potential winter gas demand for electric generation.[30] Under design winter conditions, where the temperature-sensitive gas load can increase between 10 and 20 percent (depending on the LDC), the gas available for electric generation declines substantially. As shown in Table 13, in this case, only 70 percent of total potential winter gas demand for electric generation is met, compared to 89 percent in the normal weather case. Lower levels of gas use will require offsetting increases in oil-fired generation to

[30] As explained above, oil-fired generation is used to for the remaining 11 percent of total fuel needs to ensure that electric needs are fully met.

ensure that electricity demands are fully met. Alternatively, gas-fired generators could operate at a level similar to what we have estimated for a normal 2005 winter if between 100 and 160 MDT per day of additional pipeline capacity were added.[31]

Table 13
Generation by Gas-Fired and Dual-Fueled Units (GWh)
Downstate Region 2005 Design Winter Case
4,435 MW Generating Capacity Additions Case

	Maximum Potential Gas Demand	No Post-2003 Pipeline Expansions	300 MDT/day Expansion Into Downstate	400 MDT/day Expansion Into Downstate	500 MDT/day Expansion Into Downstate
Combined Cycle Units Fueled by Gas	27,856	26,520	24,035	25,321	26,340
Other Units Fueled by Gas	9,003	8,656	8,302	8,370	8,440
Redispatched Units Fueled By Oil	0	1,038	1,632	1,509	1,072
Total	36,858	36,214	33,970	35,200	35,852
# of Days When Unrestricted Gas Market for Power Is Served	365	280	246	272	298
% Served of Unrestricted Gas Market for Power	100%	95%	88%	91%	94%

Higher than expected electric demands pose another potential risk to the gas and electric system. However, our finding that the gas and electric systems can reliably meet their future loads across the range of scenarios included in our analysis holds true, even with higher electric loads. In a 2005 case with extreme weather loads (defined as an increase in both peak demand and annual energy requirements consistent with the extreme weather peak forecast reported in the NYISO Gold Book[32]) and 4,435 MW of new capacity, electric loads can be met under all pipeline addition scenarios. In this case, slightly more oil needs to be burned by electric generators in each corresponding pipeline scenario, but total oil burn remains below historical levels and should therefore be available.

[31] As shown in Figure 17, under design winter conditions there is one day when a very small portion of upstate gas demands for electric generation cannot be fully supplied. Hence, a very small amount of oil would also need to be burned in the upstate area.

[32] See New York Independent System Operator, *2001 Load and Capacity Data* (Gold Book), pp. 4–5.

5.7 Electricity Generation Fuel Mix and Reliability Considerations

With the addition of new CCs in the NYCA market, gas will fire an increasing amount of electric generation. The new, more efficient CCs will replace output from the less-efficient, gas-fired units, output from generators burning other fuels, and imports into NYCA from other regions. This substitution will increase the portion of NYCA electricity generated from gas.

Prior to the introduction of the gas-fired CC units, the gas used for power generation in the downstate market was in dual-fuel steam units. Whenever gas was not available for these units, they simply shifted to oil. As most of the new CCs do not have either firm delivery contracts for gas or oil backup for more than a short time (if at all), the reliability of the units is subject to gas availability, something that cannot be guaranteed under current conditions.

There are three ways that the electric system can broadly maintain, and possibly enhance, its reliability as the dependence on gas increases. First, if the new units were to contract for firm gas supply and delivery services, then absent a delivery system failure, the fuel would be available when the units were dispatched to run. Secondly, the units could install a backup fuel if they could be assured that they could switch on the fly should their gas supply be interrupted. Third, if the overall system (not the CC units themselves) could have adequate oil-fueled capacity that is capable of meeting the 10- and 30-minute response time requirements.

Each of these "solutions" comes with caveats. In the first case, where the CCs contract for firm gas, the CCs would have to absorb the price of firm pipeline capacity – a cost that is much higher than the released capacity or interruptible rates they would otherwise pay. Based on the limits to surplus pipeline capacity to New York, it is unlikely that a significant number of CCs could expect to operate with gas without committing to a firm pipeline contract (likely to be a pipeline expansion). The reluctance to enter into such an agreement by a CC operator is driven by short-term economics—the lack of compensation for being a "more reliable supply" and the limited profitability of selling into the electricity market during the winter periods when the high cost capacity would be unlikely to be obtained otherwise.

Even with a firm gas contract, the diversity of the gas supply plays a role in the reliability of the unit. Clearly, if all of the units were served by a single pipeline, should that pipeline suffer any major system failure that could not be addressed by other gas supplies, then the system would still need some oil-fired generation units. These could be the CCs if they had adequate short-term oil backup on site (useable for days, not hours) in which case the steam units may be retired. Alternatively, the existing oil-fired steam electric units could be provided incentives to remain in service to assure system reliability. This is an interesting aspect of the repowering situations where there are already large storage tanks on site. Converting one of these tanks to a distillate tank (with the environmental permits to utilize the fuel as needed) would provide a new CC unit with oil availability comparable to that of an existing dual-fuel steam unit.

If the units were to have backup fuel and permits to burn it for extended periods (weeks, not days), then the units' fuel reliability would be very high. Under these conditions, it is likely that the existing steam units would be dispatched so rarely, that their opportunity costs may exceed their value in the electricity market and they would be retired.

In the third case, where the CCs do not have a firm contract for gas or a sufficient backup fuel, it is unlikely that the pipelines would be constructed. The existing steam electric units would likely remain in service and run when gas was unavailable to the CCs. In this case, the CCs would have relatively low capacity factors, and less-efficient units with higher emission rates would run more often.

The disconnect between the gas industry and the electric industry is quite stark. If one analyzes the behavior of the merchant power sector, they have little incentive to either contract for a firm gas supply or to install any substantial oil backup in the current environment. First, there is a substantial amount of released pipeline capacity available in the summer to serve the downstate market. This capacity can be had at a sizable discount from filed pipeline tariffs, providing generous savings. Secondly, the backup fuel (or firm capacity) is primarily required during the winter months when the margin on generation has traditionally been low, so the penalty for not operating on any given winter day(s) is small. Finally, there is no compensation to the generators for acquiring any backup (*i.e.*, no differential consideration in a generator's ability to participate in capacity markets).

On the pipeline side, pipelines are required by the FERC to show a market need for new capacity. The only accepted showings are executed capacity contracts. Without a demonstrable market, the pipelines will not be built. And because the incremental market is largely a power generation market, the lack of incentives on the merchant generator side effectively delay the timing of the pipeline expansions until the generators sense that there will not be adequate surplus pipeline capacity for a sufficient number of months and they contract for the space. The incentives of the two players need to be realigned if the goal of greater electric efficiency, reliable generation, and better air quality at a reasonable cost is to be achieved.

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